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Characterisation of CO_2 emissions in Canada's oil sands industry: Estimating the future CO_2 supply and capture cost curves

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Abstract

In 2007, Alberta's oil sands generated approximately one quarter of all the GHG emissions in the province. Their contribution to the total was second only to electric utilities. Together, these sectors accounted for two-thirds of all GHG emissions in the province. In the future, the oil sands sector may overtake electricity as Alberta's leading source of emissions. Thus, we generated CO_2 supply forecasts from oil sands operations in the Athabasca region as a function of bitumen and synthetic crude oil production levels to 2020. The supply is presented according to process source, by energy commodity and by CO_2 content in the source flue gas. The study includes cost curves for oil sands operations in 2020 for different H_2 production scenarios.

Between 2005 and 2020, upgrading operations contribute the most to CO_2 emissions growth, followed by SAGD and mining operations. Total CO_2 supply reaches 188 ktonnes/d by 2020, but may increase to 261 ktonnes/d if gasification of bitumen residues for H_2 production is implemented. The CO_2 supply grows five-fold during this period, or seven-fold, in the latter case. The total supply is largely determined by the production of steam and hydrogen in SAGD and upgrading operations, respectively. Low purity sources (<10% CO_2) dominate the forecast supply, driven mostly by growth in SAGD operations. Low-purity sources have capture costs over twice as high as those from the next most-abundant sources (>15% CO_2), which are driven by upgrading processes. Estimated capture costs range from \$63/tonne for gasification sources to \$172/tonne for low-purity sources. The final shape of the supply and cost curves will be strongly influenced by the extent to which gasification (for H_2 production) is adopted in future bitumen upgrading operations. Gasification involves a tradeoff between lower capture costs and increased CO_2 production, with respect to currently-dominating methane reforming-based bitumen upgrading operations.

Keywords: Alberta; oil sands; Canada; CO_2 supply; capture costs; supply curves; CO_2 emissions

1. Introduction

Canada's crude bitumen reserves, located predominantly in the province of Alberta, are substantially larger than conventional crude reserves. For this reason, the output from oil sands is widely anticipated to continue escalating for the foreseeable future. There are three regions containing most of the bitumen: Athabasca, Peace River, and Cold Lake (see Figure 1). This study focuses on the Athabasca region, which is the largest and most active zone.

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In 2008, reported GHG emissions from oil sands operations were roughly 35 million tonnes of CO_{2eq}, representing roughly one-third of the total emissions from all industrial sectors in Alberta [2]. In the same year, the Fort McMurray area yielded 38 million m^3 (239 million barrels) of synthetic crude oil (SCO) and 75.9 million m^3 (477 million barrels) of crude bitumen. Over the next ten years, SCO and bitumen production are forecast to reach 89 million m^3 (563 million barrels) and over 171 million m^3 (1.1 billion barrels), respectively [1]. Such tremendous growth rates will be accompanied by a proportional increase in CO_2 emissions due to the highly energy intensive nature of bitumen extraction and upgrading processes.

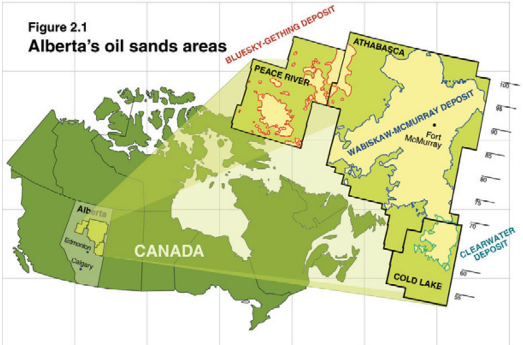

Figure 1. Alberta's Oil sands areas [1]

Carbon capture and storage (CCS) is an accepted GHG emissions mitigation technology in Alberta. The province features considerable geological formations suitable for underground storage and a large potential for use of CO_2 in enhanced oil recovery (EOR) operations. A sensible plan for a viable CCS system for the oil sands requires that both the CO_2 supply and demand be well-understood. The latter is set largely by the size of planned EOR operations and by the impacts of carbon-mitigation policies on the operations of the oil sands industry. CO_2 supply, on the other hand, is a function of several factors, including regulatory, technical, and economic considerations. This study focuses only on the CO_2 supply and is technical in its approach to studying it. Hence, only process-related issues were considered when establishing the magnitudes of CO_2 produced and captured in oil sands operations. Market, regulatory, and other non-process influences (i.e., price of oil, carbon taxes, etc.) are excluded from the analysis.

Under Alberta's *Specified Gas Reporting Regulation*, GHG emissions are reported by oil sands companies. The emissions are categorized according to: GHG gas type (CH_4, CO_2, N_2O), source type (stationary, venting, etc.), and industrial sector. However, the reported data has insufficient detail to provide an accurate estimate of the potential CO_2 supply derived from oil sands operations for two reasons. First, not all of the carbon emitted from the variety of industrial operations involved in extracting and upgrading bitumen can be feasibly captured. For instance, the GHG emissions from diesel burning in internal combustion engines from bitumen mining operations are counted in the reports, but would not readily be considered part of the CO_2 "supply" in a typical CCS system. Second, the reported figures are aggregated at the facility level, and thus, it is impossible to discern the GHG emissions distributions according to process and the purity of the various CO_2-bearing streams generated during oil sands processing.

In recognition of these gaps, our study aimed to generate CO_2 supply forecasts of oil sands operations and capture cost curves, covering operations from 2005 to 2020. The analysis makes a clear distinction between CO_2 emissions and potential CO_2 supply and characterizes the latter according to process source, energy commodity, and purity.

2. Methodology

The CO_2 supply from oil sands is a direct function of bitumen and SCO production levels. We developed an oil production forecast on the basis of publicly available data from several sources [3,4,5,6]. The forecast was divided according to operation, including mining, SAGD, and upgrading and included individual oil sands producers with planned operations to the year 2020.

The production figures of each producer were categorised according to the year when the project was expected to come on-stream and to its operational status. The status categories (current as of April, 2008) included: *Operating* – the project is currently extracting or upgrading bitumen; *Construction* – the project is currently under active construction; *Approved* – regulatory approval has been granted; *Application* – a regulatory application for proposed operations has been submitted; *Disclosure* – specific details of the project have been made public; *Announced* – a future project has been announced, but minimal details are given. On the basis of these categories, three forecast levels were specified: 1) Low – includes all projects currently operating or under construction, 2) Medium – includes low plus approved and application projects, and 3) High – includes all project status categories. Due to space restrictions, all of the results featured here are limited to the *Medium* oil sands production case, shown graphically in Figure 2. The other cases and their results can be found elsewhere [7].

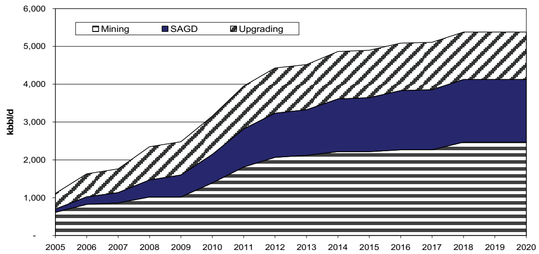

Figure 2. Oil sands production forecast 2005-2020

The CO_2 emissions are a function of the energy conversion processes involved in mining, SAGD, and upgrading. Thus, the emissions are broken down into energy commodities, shown in Figure 3. The mix of energy commodities required is ultimately responsible for the overall CO_2 emissions makeup in any given year. The energy demands and CO_2 emissions were derived from the Oil Sands Operations Model (OSOM) a stand-alone mathematical model previously developed for similar purposes [8]. Of all the CO_2 emissions from oil sands operations, only a fraction can be feasibly recovered. This "captureable" CO_2 is a function of the carbon removal technology used, the flue gas compositions, and inherent process limitations. Our results report the overall CO_2 emissions and the *captureable* CO_2 emissions from large stationary point sources, the latter being the potential CO_2 supply in the region.

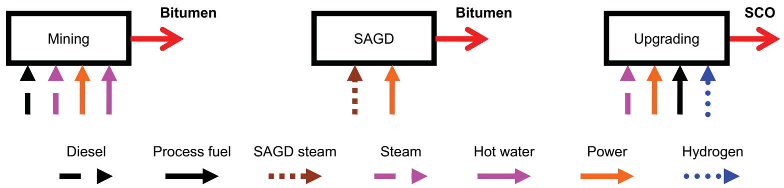

Figure 3. Energy demands of oil sands operations by commodity

The capture costs featured in the study are obtained from our in-house "Integrated Economic Model" (IEM) for CO_2 capture, compression, transport and storage [9]. The IEM models the whole CCS process by solving for material/energy balance data and equipment power demands from a CO_2 capture plant and a CO_2 transport pipeline. We only considered the capture plant; hence all costs reported here exclude transportation and storage.

3. Inputs

The CO_2 supply curves cover bitumen mining, thermal bitumen extraction via SAGD, and bitumen upgrading. Mining operations include: mining oil sands, slurry hydro-transport/conditioning, and bitumen extraction via the hot water process. SAGD operations consider: steam injection, fluid production, and bitumen separation. Upgrading operations cover: bitumen distillation (atmospheric and vacuum), coking (fluid and delayed), Hydrocracking via LC-Fining, and Hydrotreatment, for Sulphur and Nitrogen removal.

The CO_2 production from mining includes the emissions from diesel, hot water, steam, and power production. SAGD includes emissions from steam and power only, whereas upgrading operations comprise the emissions from process fuel, steam, power, and hydrogen production. The assumed energy demands in terms of the aforementioned commodities for individual oil sands operations are presented in Table 1.

Table 1. Main energy demand parameters used in the analysis [8]

Operation	Diesel l/bbl	Hot water tonne/bbl	Steam tonne/bbl	Power kWh/bbl	Process fuel MJ/bbl	Hydrogen SCF/bbl
Mining	1.71	1.08	0.01	16.4		
SAGD			0.39	3.1		
Upgrading			0.10	6.3	59	2,000

We assumed that natural gas is used for power, steam, hot water, and H_2 production. H_2 may be alternatively produced from bitumen residues (asphaltene and petcoke) via gasification. Diesel is used for trucks in mining operations. The CO_2 supply forecasts are built on the basis of utilization rates of these fuels. Our analysis excludes the use of fuel gas, a by-product of upgrading operations commonly burned in integrated SCO production facilities.

A summary of the CO_2 concentration in the flue gases used in our analyses is shown in Table 2. The concentrations are shown as a range typically found in oil sands operations, as well as the representative values that were selected for the study.

Table 2. Flue gas CO_2 concentration values according to energy commodity

CO_2 in flue gas (mole %, dry basis)	Diesel	Hot water	Steam	Power	Process fuel	Hydrogen
Typical range	10-15%	0-10%	0-10%	10-15%	0-10%	15-50%
Representative value	N/A	3.5%	3.5%	9.2%	13%	18.6% & 44%

The basis of the cost evaluation in the IEM is a stand-alone CO_2 capture plant producing 2 million tonnes per year of CO_2 (5,500 tonne/d). Post combustion capture, using KS-1 solvent at a capture rate of 90% is assumed. The capture plant generates all its steam requirements internally; hence there is no heat integration with other facilities. A steam consumption of 1.3 tonne/tonne of CO_2 was assumed. Electricity is purchased from the power grid. Flue gas desulphurisation prior to capture is not included in the cost estimates, but rather, we considered a polishing step (caustic wash) to get the sulphur level to within the specification needed in the KS-1 process.

A summary of the key IEM parameters used in the analysis is given in Table 3. All costs featured in this report are given in 2nd quarter 2008 Canadian dollars. It should be noted that until recently the oil sands industry was in an escalating cost environment. The Chemical Engineering Plant Cost Index increased 48.6 % from 2003 to 2008 (from 401.8 to 597.1), a rate increase of 8.2% per year during this period. This was in part due to escalating commodity prices and, in Alberta, chronic shortage of skilled labor. Therefore, the cost analysis featured here assumed an escalating cost environment and the results must be treated accordingly by the reader.

Table 3. Key economic inputs to the IEM

Parameter	Value
Natural Gas ($/MMBTU)	7.0
Electricity ($/MWh)	80
Discount rate (%)	10
Plant Life (Years)	30

4. Results

4.1. CO_2 supply forecasts

Upgrading operations contribute the most to CO_2 emissions growth, followed by SAGD and mining production. In terms of supply, upgrading (sans gasification) leads until 2016, as shown in Figure 4. Post-2016, SAGD operations surpass upgrading as the main source of carbon. Total CO_2 supply (without gasification) grows at an average annual rate of 34%, reaching 188 ktonnes/d by 2020. An additional 24-73 ktonnes/d could be available if gasification of bitumen residues is implemented, raising the CO_2 supply to 261 ktonnes/d by 2020. The net CO_2 supply represents 88% of the total CO_2 emissions from oil sands operations (excluding gasification) and 91% if gasification is considered.

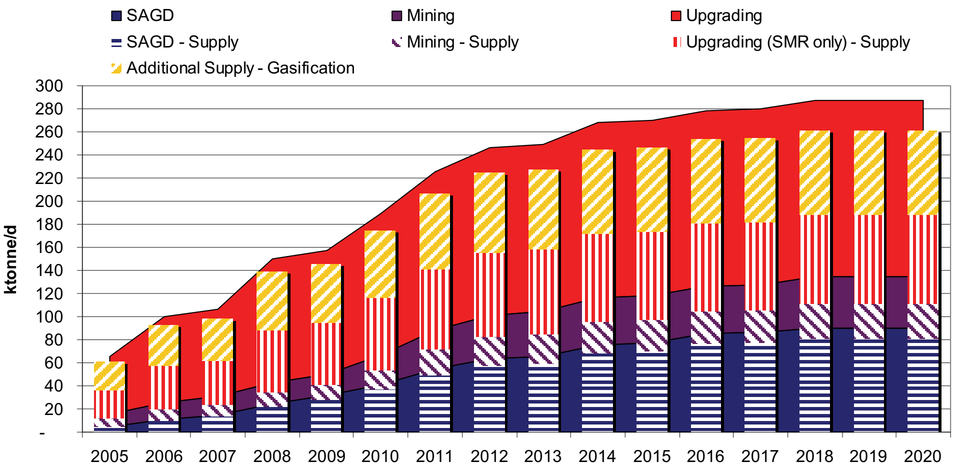

Figure 4. CO_2 emissions and supply 2005-2020 according to oil sands process

The results are presented with and without gasification due to the fact that most current upgrading operations rely on hydrogen production via steam methane reforming (SMR) plants. Gasification is seen as an alternative technology, which may be adopted by some future projects in lieu of the currently less expensive, more well-known SMR technology. Our analysis shows the potential additional CO_2 supply derived from gasification as an addition to the total supply from "traditional" processes in mining, SAGD, and upgrading operations.

The breakdown of CO_2 sources according to commodity is presented in Figure 5. The total CO_2 supply for mining, SAGD, and upgrading operations is largely determined by the production of two commodities: steam and hydrogen. CO_2 from steam generation is roughly twice as much as that associated with H_2 production if only SMR is used. But, if gasification of upgrading residues is used, H_2 manufacture becomes the main source of CO_2, reaching 45% of the total CO_2 production. Power, hot water, process, and diesel fuel combined account for roughly 16% of CO_2 production. The analysis revealed that the total CO_2 supply (excluding gasification) is roughly equivalent to the combined emissions from steam, hydrogen (SMR), and power production for all years under study.

Figure 6 shows the CO_2 supply divided according to the mole fraction (dry basis) of CO_2 in the source gas stream. Accordingly, the purity ranges are: 0%-10%, 10%-15%, 15%-20%, and 30%-50%. The CO_2 from diesel fuel use in mining operations is excluded from the curves, as it unrecoverable by current CCS techniques.

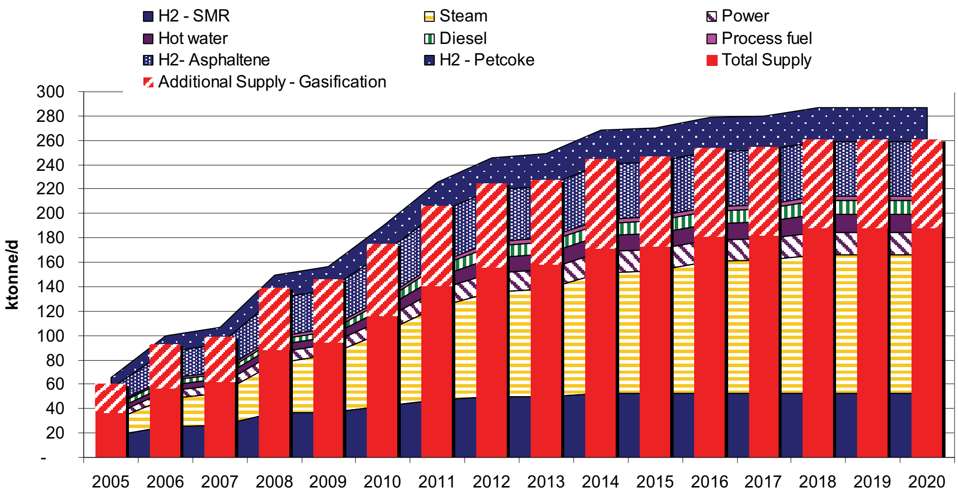

Figure 5. CO_2 emissions and supply 2005-2020 according to energy commodity

Excluding gasification, process streams with a purity of <10% are by far the largest source of CO_2 between 2005 and 2020, followed by 15%-20% streams and 10%-15% sources. The former supply grows from 16 ktonnes/d to 119 ktonnes/d between 2005 and 2020. The production figures for the latter two sources are 17-52 ktonnes a day and 4-17 ktonnes CO_2/d, respectively, for the period between 2005 and 2020. High purity CO_2 sources from gasification range from 32 ktonnes/d to 97 ktonnes/d for asphaltene gasification and from 41-125 ktonnes/d for petcoke gasification. The growth in low-purity (0%-10%) is primarily driven by growth in SAGD operations, while increases in medium (15%-20%) and high-purity (30%-50%) sources are tied to growth in upgrading operations.

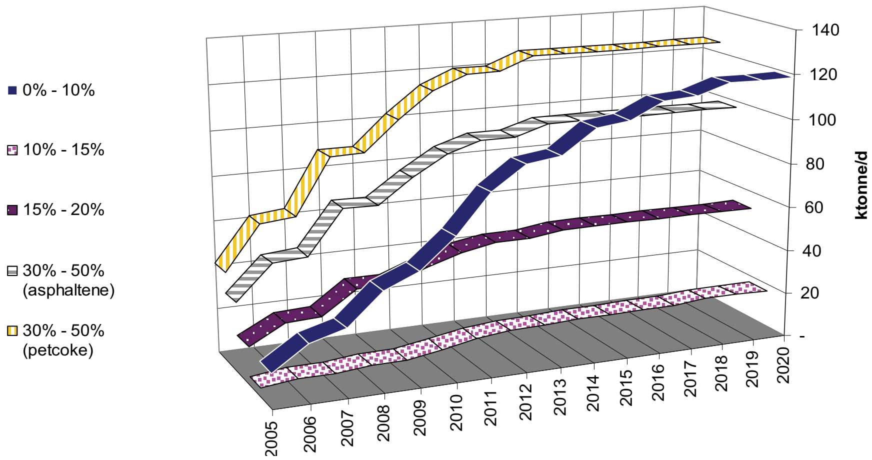

Figure 6. CO_2 supply 2005-2020 according to source purity

4.2. Cost curves

Table 4 summarizes the cost of capture for various representative waste gas streams, calculated using the IEM model. It shows the trend that the cost of CO_2 capture decreases as the CO_2 concentration in the flue gas increases.

Table 4. IEM capture cost estimates for representative oil sands flue gas streams according to CO_2 concentration

2008 Canadian dollars $/tonne CO_2	**3.5% CO_2**	**9.2% CO_2**	**13% CO_2**	**18.6% CO_2**	**44% CO_2**	**99+% CO_2**
Capital Costs ($MM)	1,234	629	479.8	396.8	263.3	117
Capital Charges	71.2	36.3	28.8	22.9	15.2	6.2
Fixed Costs	43.8	20.5	16.4	13.1	8.6	1.75
Variable Costs						
- electricity	23.2	10.5	8.5	6.6	4.5	8.5
- natural gas	26.5	28.4	30.2	28.8	30.5	0.2
- others	6.9	5.9	6.0	4.6	4.4	1.15
Total	171.6	101.6	89.8	76.0	63.2	18.8

The cost curves for the year 2020 are presented in Figures 7 and 8. Figure 7 excludes gasification sources whereas Figure 8 replaces H_2 from SMR with petcoke gasification. These Figures include pure (99+%) CO_2 from three existing Benfield H_2 units operating in the Fort McMurray area. CO_2 supply from these units is modest, totaling 5.5 ktonnes/d. These units do not require additional capture to produce CO_2, just gathering, dehydration and compression. Hence, the cost of CO_2 capture estimated by the IEM is $18.8/tonne, as shown in Table 4.

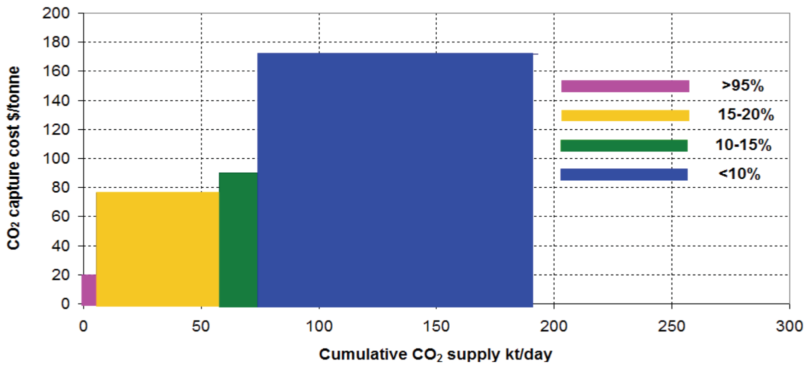

Figure 7. CO_2 supply in 2020 excluding gasification sources

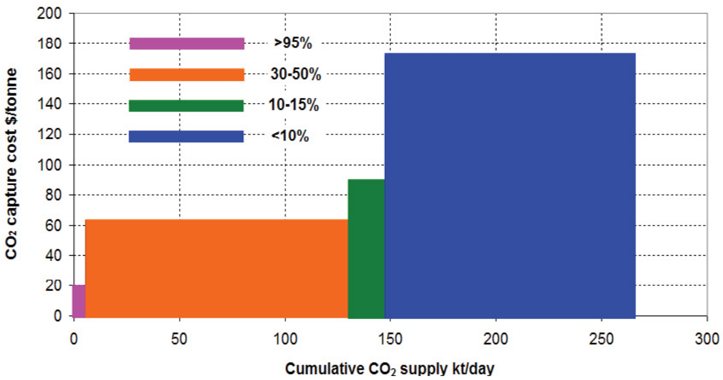

Figure 8. CO_2 supply in 2020 including gasification sources

The most striking feature of the cost curves is that the bulk of the supply is available from low-concentration sources, which are the most expensive to capture. This rise in low-quality CO_2 streams is strongly related to the high growth in SAGD operations; specifically, the large increase in steam demands for SAGD operations may drive the production of low-concentration flue gases to peak highs. H_2 production is the second largest supply component, followed by medium-purity sources (10%-15%). "Pure" sources (>95%) are insignificant in comparison to the rest.

There is a key tradeoff in cost vs. supply depending on the chosen H_2 production technology. If only SMR is used, less CO_2 is produced, but it is costlier to capture it, whereas if only gasification is used, the cost of capture drops, but the supply increases by a factor of 2.4 (125 ktonne/d vs. 52 ktonne/d). These figures represent extremes for the forecast CO_2 supply from upgrading operations. The actual future supply will likely lie in between, depending on the extent to which gasification of bitumen residues for H_2 production is adopted in the industry.

5. Conclusions

The CO_2 supply potential from oil sands operations due to CCS implementation in the near future is substantial. It grows five-fold between 2005 and 2020, with the possibility of increasing seven-fold, if gasification dominates H_2 production in upgrading processes. Our results suggest that the bulk of the supply will come from upgrading and SAGD operations. In terms of energy demands, steam, hydrogen, and power generation processes are the main contributors to CO_2 supply growth in oil sands operations, in that specific order. The choice of H_2 production technology has a substantial impact on the supply curves; the wide adoption of gasification processes could ultimately increase CO_2 supply by 40%-60%.

Low purity sources (<10% CO_2) are poised to dominate the forecast supply, driven mostly by growth in SAGD operations. Low-purity sources have capture costs over twice as high as those from the next most-abundant sources (>15% CO_2), which are driven by hydrogen demands for upgrading processes. Capture costs range from $172/tonne for low-purity sources, to $63/tonne for gasification sources. There is also a minute supply of very high purity CO_2 from existing Benfield-type H_2 plants that can be processed for $19/tonne. The final shape of the supply and cost curves will be strongly influenced by the extent to which gasification (for H_2 production) is adopted in future bitumen upgrading operations. Gasification involves a tradeoff between lower capture costs and increased CO_2 production, with respect to SMR-based upgrading operations. By 2020, the minimum estimated potential supply is 188 ktonnes/d and the maximum is 261 ktonnes/d, assuming gasification is the dominant H_2 production technique.

Acknowledgement

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